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L-13-073

10 CFR 50.73(a)(2)(iv)(A)

ATTN: Document Control Desk
U. S. Nuclear Regulatory Commission
Washington, DC 20555-0001

SUBJECT:
Perry Nuclear Power Plant
Docket No. 50-440, License No. NPF-58
Licensee Event Report Submittal

Enclosed is Licensee Event Report (LER) 2013-001, "Loss of Feedwater Results in Automatic Reactor Protection System Actuation." There are no regulatory commitments contained in this submittal.

If there are any questions or if additional information is required, please contact Mr. Thomas Veitch, Manager – Regulatory Compliance, at (440) 280-5188.

Sincerely,

Vito A. Kaminskas

Enclosure:
LER 2013-001

cc: NRC Project Manager
NRC Resident Inspector
NRC Region III

NRC FORM 366 (10-2010) U.S. NUCLEAR REGULATORY COMMISSION

APPROVED BY OMB NO. 3150-0104 EXPIRES 10/31/2013

Estimated burden per response to comply with this mandatory collection request: 80 hrs. Reported lessons learned are incorporated into the licensing process and fed back to industry. Send comments regarding burden estimate to the FOIA/Privacy Section (T-5 F53), U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001, or by internet e-mail to infocollects.resource@nrc.gov, and to the Desk Officer, Office of Information and Regulatory Affairs, NEOB-10202 (3150-0104), Office of Management and Budget, Washington, DC 20503. If a means used to impose an information collection does not display a currently valid OMB control number, the NRC may not conduct or sponsor, and a person is not required to respond to, the information collection.

LICENSEE EVENT REPORT (LER)

(See reverse for required number of digits/characters for each block)

1. FACILITY NAME	2. DOCKET NUMBER	3. PAGE
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4. TITLE

Loss of Feedwater Results in Automatic Reactor Protection System Actuation

5. EVENT DATE			6. LER NUMBER			7. REPORT DATE			8. OTHER FACILITIES INVOLVED	
MONTH	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REV NO.	MONTH	DAY	YEAR	FACILITY NAME	DOCKET NUMBER
01	22	2013	2013	- 001	- 00	03	21	2013	FACILITY NAME	DOCKET NUMBER

9. OPERATING MODE

1

10. POWER LEVEL

99.8

11. THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: *(Check all that apply)*

☐ 20.2201(b)	☐ 20.2203(a)(3)(i)	☐ 50.73(a)(2)(i)(C)	☐ 50.73(a)(2)(vii)
☐ 20.2201(d)	☐ 20.2203(a)(3)(ii)	☐ 50.73(a)(2)(ii)(A)	☐ 50.73(a)(2)(viii)(A)
☐ 20.2203(a)(1)	☐ 20.2203(a)(4)	☐ 50.73(a)(2)(ii)(B)	☐ 50.73(a)(2)(viii)(B)
☐ 20.2203(a)(2)(i)	☐ 50.36(c)(1)(i)(A)	☐ 50.73(a)(2)(iii)	☐ 50.73(a)(2)(ix)(A)
☐ 20.2203(a)(2)(ii)	☐ 50.36(c)(1)(ii)(A)	☒ 50.73(a)(2)(iv)(A)	☐ 50.73(a)(2)(x)
☐ 20.2203(a)(2)(iii)	☐ 50.36(c)(2)	☐ 50.73(a)(2)(v)(A)	☐ 73.71(a)(4)
☐ 20.2203(a)(2)(iv)	☐ 50.46(a)(3)(ii)	☐ 50.73(a)(2)(v)(B)	☐ 73.71(a)(5)
☐ 20.2203(a)(2)(v)	☐ 50.73(a)(2)(i)(A)	☐ 50.73(a)(2)(v)(C)	☒ OTHER
☐ 20.2203(a)(2)(vi)	☐ 50.73(a)(2)(i)(B)	☐ 50.73(a)(2)(v)(D)	Specify in Abstract below or in NRC Form 366A

12. LICENSEE CONTACT FOR THIS LER

FACILITY NAME	TELEPHONE NUMBER *(Include Area Code)*
Perry Nuclear Power Plant, John Pelcic, Compliance Engineer	(440) 280-5824

13. COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT

CAUSE	SYSTEM	COMPONENT	MANU-FACTURER	REPORTABLE TO EPIX	CAUSE	SYSTEM	COMPONENT	MANU-FACTURER	REPORTABLE TO EPIX
E	EJ	ASU	C782	Y	E	EJ	INVT	C782	Y

14. SUPPLEMENTAL REPORT EXPECTED

☐ YES *(If yes, complete EXPECTED SUBMISSION DATE).* ☒ NO

15. EXPECTED SUBMISSION DATE

MONTH	DAY	YEAR

ABSTRACT *(Limit to 1400 spaces, i.e., approximately 15 single-spaced typewritten lines)*

On January 22, 2013, at 0332 hours, the reactor protection system (RPS) automatically actuated due to a loss of feedwater flow to the reactor pressure vessel (RPV). There were no complications during the shutdown as all control rods fully inserted and pressure was maintained by normal means. The High Pressure Core Spray (HPCS) and the Reactor Core Isolation Cooling (RCIC) systems actuated based on a valid reactor water level initiation and injected to restore RPV water level.

The cause of the event was failure of a balance-of-plant inverter/static transfer switch, which provides electrical power to the digital feedwater control system. A circuit card in the static transfer switch degraded, which affected operation of the inverter. The electrical loads serviced by the inverter/static transfer switch were placed on an alternate power source. This alignment will continue until permanent repairs are made which are currently scheduled for the next refueling outage.

The safety significance of this event is considered to be small. This event is being reported in accordance with 10 CFR 50.73(a)(2)(iv)(A) as an event or condition that resulted in an automatic actuation of the RPS, HPCS, and RCIC systems, and Operational Requirements Manual section 7.6.2.1, which requires a Special Report submittal following an Emergency Core Cooling System actuation and injection into the reactor coolant system.

NARRATIVE

Energy Industry Identification System (EIIS) codes are identified in the text as [XX].

INTRODUCTION

On January 22, 2013, at 0332 hours, the Reactor Protection System (RPS) [JC] automatically actuated in response to a low reactor water level (i.e., Level 3, 178 inches above the top of active fuel (TAF)) signal due to a loss of feedwater flow to the reactor pressure vessel (RPV). At the time of the event, the plant was in Mode 1 (i.e., Power Operation) with the reactor operating at 99.8 percent of rated thermal power (RTP). Reactor water level continued to decrease until the High Pressure Core Spray (HPCS) [BG] and the Reactor Core Isolation Cooling (RCIC) [BN] systems automatically started to restore RPV level. At 0657 hours, notification was made to the NRC Operations Center (Reference ENF No. 48688) in accordance with 10 CFR 50.72(b)(2)(iv)(A), emergency core cooling system (ECCS) discharge into the reactor coolant system; 10 CFR 50.72 (b)(2)(iv)(B), actuation of the reactor protection system when the reactor is critical; and 10 CFR 50.72(b)(3)(iv)(A), valid actuation of several specified systems. This event is being reported in accordance with 10 CFR 50.73(a)(2)(iv)(A) as an event or condition that resulted in automatic actuation of the RPS, HPCS, RCIC, Division 3 Emergency Diesel Generator (EDG) [EK], Division 3 Emergency Service Water (ESW) [BI], Division 1 ESW, and containment isolation valves [JM].

This report also satisfies the Operational Requirements Manual (ORM) section 7.6.2.1, which requires a Special Report submittal following an ECCS actuation and injection into the reactor coolant system.

EVENT DESCRIPTION

On January 22, 2013, the plant was operating in Mode 1 at 99.8 percent RTP. The plant was in a normal electrical line-up with all EDGs and ECCS systems operable. The feedwater system was in its normal alignment with turbine-driven reactor feedwater pumps (RFP) A and B in automatic 3-element level control. The motor-driven feedwater pump (MFP) was in standby.

At 0332 hours, an RPS actuation occurred that resulted in an automatic reactor scram. All control rods fully inserted. The RPS actuated in response to receipt of a low reactor water level (i.e., Level 3) signal due to a loss of feedwater flow. RFPs A/B had run back to minimum flow and, therefore, were no longer providing the required feedwater flow to the RPV. The MFP did not receive a start signal because the RFPs had not tripped.

RPV water level continued to decrease and when it reached the Level 2 setpoint (i.e., 130 inches above the TAF), the RCIC and HPCS systems started and injected into the RPV. Both RFPs and the main turbine tripped. Containment isolation occurred with isolation of all required valves. Both Reactor Recirculation [AD] pumps tripped as designed. The Division 3 EDG, which supplies emergency electrical power to the HPCS system started, but did not load onto the bus, as designed. The MFP started as designed when the RFPs tripped. At approximately 0335 hours, the HPCS and RCIC systems and the MFP stopped injecting when the Level 8 setpoint (i.e., 219 inches above the TAF) was reached. The lowest RPV water level reached during the event was 79.8 inches above the TAF. RPS was reset at 0413 hours. Mode 4, Cold Shutdown was entered at 2036 hours when the average reactor coolant temperature decreased to less than 200 degrees Fahrenheit.

NARRATIVE

CAUSE OF EVENT

The RPS scram was caused by an electrical transient in the balance-of-plant (BOP) 120 volt AC Uninterruptable Power Supply (UPS) system [EJ]. The transient was caused by a degraded static transfer switch component [ASU] coincident with a failed DC to AC inverter [INVT]. The static transfer switch did not seamlessly transfer the loads to the alternate source. The inverter was found on the alternate source with the fail light illuminated and its protective fuse actuated. The control logic for the Digital Feedwater Control system (DFWCS) is one of the electrical loads serviced by the UPS. Disruption of the DFWCS logic due to the electrical transient affected the feedwater system by driving the RFP controllers to minimum flow with no start signal being sent to the MFP per design. As a result, feedwater flow was lost to the RPV and the RPS actuated, as designed, when RPV Level 3 was reached.

No failed internal components were identified through initial troubleshooting of the BOP inverter and static transfer switch. A root cause evaluation found that there was inadequate preventive maintenance (PM) performed on the static transfer switch, which was designated as a single point vulnerability (SPV) critical component. The sensing and transfer card on the static transfer switch had degraded and not been designated for replacement under the PM program. The static transfer switch attempted to transfer loads to the alternate source. The resultant cycling of loads on the inverter affected performance of the silicon controlled rectifiers (SCRs), which convert DC to AC current, and ultimately caused the transient.

A contributing cause was inadequate reliability improvements for the inverter and static transfer switch. These components are located near an exterior roll-up steel door. Operation of the inverter at low ambient temperatures or at sharp changes in temperature could cause the SCRs to misfire resulting in a momentary short circuit condition. High winds and cold outside temperatures existed at the time of the event.

Another contributing cause was that opportunities were missed in 2007-2009 to objectively evaluate and resolve reliability issues with the inverter and static switch and PM requirements through use of the corrective action program.

EVENT ANALYSIS

The UPS provides a highly reliable source of 120 VAC electrical power to specific plant loads. Power to the BOP loads is supplied by a 125V battery and is routed through a distribution bus, an inverter to convert DC to AC power, and a static transfer switch. If the inverter output voltage drops too low, the static transfer switch will transfer to the alternate source. The UPS is not controlled by Technical Specifications and is not essential to safe shutdown functions.

There were no complications during the shutdown as all control rods fully inserted and pressure was maintained by normal means. The RPS functioned as designed.

The scram event, including plant response, is bounded by the Loss of Feedwater Flow transient evaluated in the Updated Safety Analysis Report (USAR) Chapter 15, Accident Analysis, Section 15.2.7. As a direct result of the scram, no plant parameters challenged the transients as described in the USAR. This transient is categorized as an incident of moderate frequency.

NARRATIVE

A probabilistic risk assessment (PRA) was performed for this event. The PRA assessment calculated a change in core damage frequency (delta CDF) in this case to be 9.0E-08/yr and a delta large early release frequency (LERF) of 4.6E-08/yr. The delta CDF and delta LERF values are well below the acceptable thresholds of 1.0E-06/yr and 1.0E-07/yr respectively as discussed in Regulatory Guide 1.174. Plant configurations with changes in CDF of less than 1.0E-06 and LERF of less than 1.0E-07 are not considered to be significant risk events. Based on the PRA results, the safety significance of this event is considered to be small.

ORM section 7.6.2.1 requires a Special Report be submitted following an ECCS actuation and injection into the reactor coolant system. The report shall include a description of the circumstances of the actuation and the total accumulated actuation cycles to date. The current value of the usage factor for each affected safety injection nozzle shall be provided when its value exceeds 0.70. Following the scram, the HPCS system actuated once for level control and injected into the RPV for approximately three minutes. This injection brings the total number of HPCS injections to 43 over the life of the plant. The current design Cumulative Fatigue Usage Factor (CFUF) for the limiting location of the HPCS nozzle is 0.567. The number of design HPCS injections is 60. The number of operating HPCS injections is bounded by the design allowance. The current design CFUF value is less than ORM Special Report Limit (0.70).

CORRECTIVE ACTIONS

Initial troubleshooting and problem solving activities were completed; no failed components were found in the inverter or static transfer switch. The Gate Driver and Logic Power Supply circuit cards in the static transfer switch were replaced. A temporary enclosure (i.e., curtain) was erected around the inverter and static transfer switch to protect them from affects of cold temperatures.

An Operational Decision Making Issue (ODMI) evaluation was prepared and approved to operate in this alignment under administrative controls through the next refueling outage. The power plant was then restarted with BOP 120 VAC electrical loads aligned to the alternate power supply. The circuit was classified as a Protected Train which prevented further troubleshooting efforts. The following repairs are planned for the next refueling outage to restore the inverter and static transfer switch to a state of continued reliability:

- Replace the Sensing and Transfer circuit card in the static switch and complete troubleshooting to identify and replace any other failed or degraded components.
- Replace the circuit cards within the BOP inverter (i.e., modulation index, synchronizer, reference oscillator, logic power supply, and gate driver) since they are outside the PM program recommended replacement frequency.

Other corrective actions planned include:

- Revise the preventive maintenance plan to replace the Static Switch Sensing and Transfer card in accordance with the recommended PM program frequency (i.e., 10 years).
- Complete the review of critical systems with single point vulnerabilities. Create functional locations for sub-components and develop proper PM program strategies and mitigation strategies. 26 plant systems were previously reviewed prior to this failure, 23 remain.

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- Create a PM task to replace the BOP inverter cards in accordance with the recommended PM program frequency (i.e., 12 years).
- Evaluate and implement a solution to the static transfer switch SPV to resolve the temperature sensitivity issue and harden the design such that a failure does not cause a loss of feedwater.

PREVIOUS SIMILAR EVENTS

A review of LERs and the corrective action database for the past three years did not identify any previous similar events or condition reports relevant to the inverter/static transfer switch failure mechanism. Corrective actions for the following RPS actuations were reviewed. None of the actions would have been reasonably expected to have prevented the event documented in this LER.

LER 2012-001, Manual Reactor Protection System Actuation due to Automatic Turbine Generator Runback

LER 2010-003, Loss of Control Rod Drive Header Pressure Results in Manual RPS Actuation

LER 2009-001, MSR High Level Signal Causes Turbine Trip and Reactor Protection System Actuation

COMMITMENTS

There are no regulatory commitments contained in this report. Actions described in this document represent intended or planned actions, are described for the NRC's information, and are not regulatory commitments.